1994 CONVENTIONAL

ENHANCED OIL RECOVERY ROYALTY

GUIDELINES

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ALBERTA DEPARTMENT OF ENERGY
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PREFACE

These guidelines are issued to assist operators and participants in the application, approval and administration of the enhanced oil recovery royalty relief program under the Enhanced Recovery of Oil Royalty Reduction Regulation (AR 348/93) ("the Regulation"). This program, which began in 1977, provides for the Crown sharing in costs associated with enhanced oil recovery by a reduction to crude oil royalty.

This document replaces Information Letter 80-9 and any previously issued guidelines, particularly:

i) "Procedures for Application, Approval and Administration of Section 4.2 of the Petroleum Royalty Regulation," which became effective January 1, 1983; and

ii) "Conventional Enhanced Oil Recovery Royalty Guidelines", which were authorized under section 11 of the Petroleum Royalty Regulation. These guidelines became effective June 1, 1990.

This document reflects policies and procedures as of January 1, 1994. Any subsequent changes will be communicated to industry.

In the event of any conflict, the Mines and the Minerals Act and the Regulation shall take precedence over these guidelines.

The Department of Energy is prepared to assist operators and participants in resolving questions or concerns they may have concerning the administration of this program.

1.0 INTRODUCTION

1.1 Program Overview

The Alberta Government is encouraging the use of enhanced oil recovery (EOR) methods to conserve the province's petroleum resource. EOR recovery methods that use the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen or chemicals, allow for the recovery of additional oil. In order to promote this additional recovery, the Crown has agreed to share in incremental costs that are over and above the cost of conventional recovery methods by forgoing royalties on a portion of incremental tertiary production.

Application

To receive EOR royalty relief for a scheme, the operator must apply to the Department of Energy. The operator must also apply for scheme approval to the Alberta Energy and Utilities Board (AEUB)* under Section 26 of the Oil and Gas Conservation Act.

The application(s) must include detailed technical and economic data on the base case (usually waterflood) and on the EOR proposal. EOR royalty relief is based on eligible costs approved by the Department.

Detailed procedures for application are described in Section 3.0.

Approval

The Department reviews each application for EOR royalty relief to determine if the scheme meets the criteria set out in the Regulation. The Department will also seek the AEUB's advice on the technical parameters of the proposed scheme.

If the scheme meets the eligibility criteria, the Minister will approve the scheme for EOR royalty relief under the Enhanced Recovery of Oil Royalty Reduction Regulation.

The detailed process for approval is described in Section 4.0.

Administration of Approved Schemes

The Crown shares in the allowable incremental costs (royalty relief) by reducing the amount of royalty due on incremental crude oil production; this is granted on a monthly basis.

*Formerly the Energy Resources Conservation Board (ERCB) and Public Utilities Board (PUB).

Estimates of the incremental costs of the EOR scheme for the relief year must be submitted by the operator to the Department by December 31 of the preceding year. Interim relief is based on the annual estimated costs subject to a maximum of the Crown's royalty share of incremental oil revenue.

If the estimated costs of a scheme exceed the annual incremental production revenue, the excess costs are carried forward to the subsequent year(s).

A report of actual costs for the relief year must be submitted by the operator/participant to the Department by June 30 of the following year. Upon verification by the Department, an interim royalty relief adjustment will be made. A relief adjustment may also be made following an audit.

Detailed procedures for program administration are provided in Section 5.0.

Termination of Schemes

An operator may decide to terminate an EOR scheme, or the Department may terminate the eligibility of a scheme for royalty relief.

The basis for terminating royalty relief for a scheme is described in Section 4.0.

1.2 Overview of Allowable Costs

Allowable EOR costs are those that are eligible and incremental to the base case recovery scheme approved by the Department. The eligible incremental costs include defined capital expenditures and operating costs and allowances as set out in Section 2.0. The major cost categories are:

- Capital
- Injectants
- Consumed Energy
- Transportation
- Breakthrough Processing Allowance
- Overhead Allowance

1.3 Filing Requirements--General

Estimated Costs

- The due date for filing is December 31 before the reporting year. If the estimates are to be reflected in the relief provided beginning January of the reporting year, estimates must be submitted by October 31 of the previous year.

- Filing can be done only by the operator of the scheme.

- Required schedules:
    - Schedule 1 (estimated summary cost schedule)
    - Schedule 11 (estimated oil production)
- Revised estimates will not be accepted after September 30 of the reporting year.

Actual Costs

- The due date for filing is June 30 following the reporting year.
- Filed by the operator for hydrocarbon schemes.
- For nonhydrocarbon schemes, each participant must file a Schedule 5.
- Scheme participants must file a Schedule 2 if any grants and/or other incentives have been received from a government.
- Required schedules:
    - Schedule 2 (capital expenditure summary)
    - Schedule 5 (nonhydrocarbon fluids injected)
    - Schedule 6 (consumed energy summary)
    - Schedule 13 (breakthrough fuel and flare volume)
- Nil schedules are not required.

Section 6.0 provides the details of filing requirements. Details on calculation of royalty relief are provided in Section 7.0.

1.4 Effective Date of Guidelines

January 1, 1994.

2.0 ALLOWABLE COSTS

The program is intended to allow deduction of eligible costs that are incremental to the base recovery scheme. The eligible costs cover defined capital expenditures and operating costs and allowances that are detailed below. An allowance of 25 per cent (15 per cent for vertical EOR schemes) of all defined eligible costs is provided to cover undefined costs and overhead. Eligible EOR costs are net of grants and/or other incentives received from a government.

2.1 Allowable Capital Expenditures

Eligible capital costs include defined incremental tangible and intangible expenditures (drilling and surface EOR facilities other than those for gathering, compressing not specific to injection, and processing natural gas).

Incremental capital expenditures eligible for EOR royalty relief are:

1) Development of production and injection wells

- Drilling
- Casing and cementing
- Services and supplies
- Completion costs
- Initial installation of an artificial lift in a newly drilled well in an approved EOR scheme

2) Major workovers

- Conversion of wells from producer to injector or vice versa
- Re-perforation
- Stimulation
- Reduce water, solvent or chase gas production with cement squeeze
- Sand control procedures
- Introduction of artificial lift in a well that was shut-in before implementation of the miscible flood, but which is now required for the miscible flood
- Re-activation of shut-in, suspended or abandoned wells

Following initial conversion or introduction of the artificial lift, major workover refers to the type rather than the amount of expenditure. Generally, only operations and expenditures that affect the reservoir rock are eligible as a major workover. Operations and expenditures related to the wellbore or downhole production equipment are considered to be routine workovers, and are not an eligible cost for royalty relief.

A routine workover includes repairing, replacing or upgrading lift systems, pulling and replacing leaking tubing, casing repair, costs incurred for the movement of packers, etc. The introduction of artificial lift systems to wells drilled before miscible flood commencement, other than wells that were shut-in under waterflood and reactivated under miscible flood, and the replacement of existing artificial lift systems are also considered to be routine workovers

and are not an eligible deduction. The initial purchase and installation of the packer and sliding sleeve assembly, and subsequent costs incurred to move the assembly downhole, are eligible. However, wireline work involving changes to the sliding sleeves are routine and are not eligible.

3) Injection systems

- Pumps
- Compressors (booster compressors are not eligible unless they form part of the injection facility and are solely dedicated to the miscible flood)
- Mixing facilities
- Power generators
- Housing for equipment

4) Production and fluid handling facilities

- Separators and satellites
- Batteries
- Produced water disposal facilities
- Fluid cleanup or separation facilities for substances such as emulsions, sand or noxious gases
- Subsurface production pumps for wells drilled after commencement of miscible flood or for wells shut-in under waterflood and reactivated under miscible flood

5) Generating facilities for nonhydrocarbon displacement fluids

- Carbon dioxide generation facilities
- Nitrogen generation facilities
- Other nonhydrocarbon generation facilities

6) Storage facilities on site for injection fluids and chemical additives

7) Pipelines used entirely within and exclusively for the EOR scheme area

- Production
- Injection
- Tie-ins

8) Pollution control equipment

9) Water injection system expansion

- For horizontal miscible floods using the water-alternating-gas process

10) Interest on construction is at the Alberta Treasury Branch prime rate plus one per cent. For new schemes, this is recognized as being from the beginning of construction to either the commissioning of the asset or injection start-up, whichever is earlier. For scheme expansions (i.e., phased schemes), interest on construction is recognized from the beginning of construction until the commissioning of the asset.

11) Eligible previous capital expenditures, amortized at 10 per cent per year (straight-line basis) from the commencement of productive use to the injection start-up date for the scheme (new schemes) or the date they were dedicated to the scheme (existing schemes).

    Should an EOR scheme under experimental royalty status become commercial, the capital from the experimental scheme will be brought forward to the start of the commercial scheme by amortizing it at the rate of 10 per cent per year on a straight line basis.

Used equipment (owned by the operator or working interest owners) added to the scheme will be allowed at amortized value. The actual cost of used equipment purchased for the scheme will also be allowed. In the case of a non-arm's-length purchase, the fair value of equipment will be used. Under no circumstances will natural gas processing facilities qualify as capital for EOR royalty relief.

The direct field labour component of capital expenditures are eligible. Operating and maintenance expenses and capital expenditures not defined above, or not subsequently approved by the Department, are ineligible. Ineligible costs include, but are not limited to, in-house engineering and design, allocated head office costs, and indirect office labour.

Eligible capital expenditures may be claimed in the year the asset is commissioned.

During the life of the scheme, the eligible capital expenditures are amortized at the annual rate of 30 per cent on the declining balance. The unamortized capital base will continue as an eligible cost as long as there continues to be incremental oil production ("t" factor x gross oil production) from the approved scheme. Subsection 5.5 provides additional comments on the unamortized capital base. Subsection 5.3 outlines how the "t" factor is determined.

2.2 Allowable Operating Costs and Allowances

Eligible operating allowances are provided for the injected material, transportation of the material to the scheme, and the energy or fuel required to inject the material into the pool. Also, corrosion monitoring and inhibition expenses for injecting material in nonhydrocarbon schemes are eligible. Allowable injection volumes and valuation are addressed in Subsections 2.3 and 2.4, respectively. Subsection 2.5 addresses other operating costs and allowances in more detail. Subsection 2.6 provides detail on the allocation of cost allowances for Gas Royalty and EOR.

2.3 Allowable Quantity of Injectants

The Department uses the following concepts in establishing the allowable quantity of injectants.

Proprietary Injection (Indigenous Production)

For each product, the proprietary injected amount is the lesser of the following:

a) the gigajoules (GJs) of gas and volume of gas products allocated to the EOR participant's Injection Scheme on the Owner Activity Statement (OAS). This is the scheme (indigenous) production allocated to the EOR participant.

OR

b) the GJs of gas and volume of gas products injected into the Injection Scheme by or on behalf of the EOR participant. The participant's allocated share of indigenous production must be used fully (i.e., claimed as proprietary) before any purchased injectant may be claimed.

The determination of proprietary injected amount is made each month. For scheme participants that have casinghead gas sales contracts in effect before January 1, 1994, adjustments will be made to exclude these sales from the indigenous production.

All production and injection wells in an EOR scheme must be associated with the same Injection Scheme within the Gas Royalty system. Gas Royalty clients and EOR participants must also be an exact match.

EOR participants may over/under-deliver injectant to the scheme according to working interest ownership. There may be a situation where those participants under-delivering injectant are injecting less than their allocated share of indigenous production. In such circumstances, the participant will be required to claim proprietary valuation on an amount equal to the allocated share of indigenous production.

For example, assume there are two participants in a scheme, each with a 50 per cent working interest, and the following occurs for the year (based on OAS method described above).

Participant	Annual Indigenous Production	Proprietary Injection	Purchased Injection	Total Annual Injection
A	50	50	70	120
B	50	40	40	80
Total	100	90	110	200

In this case, participant B's proprietary injectant amount will be increased to 50 and the purchased amount reduced to 30 for purposes of royalty relief. The total eligible injectant amount for B remains unchanged at 80. Any annual adjustment to the purchased amount will be allocated proportionally to all months in which purchased injection occurred throughout the year.

If a participant's total injection is less than that participant's allocated share of indigenous production, the unused indigenous production will be carried forward to the next year for that participant. The amount carried forward will be added to the participant's January indigenous production of the next year. For example, assume participant B had no purchased injection and participant A's purchased injection amount is 110 in the above illustration. In this case, participant B would be required to carry forward 10 units of indigenous production to January of the following year.

Purchased Injection

Every month, for each product, the purchased injection GJs or volumes are derived from the Owner Activity Statement as follows:

Scheme Injection Allocation - Scheme Production Allocation = Purchased Injectants
(Purchased Injectants = 0 if scheme production exceeds scheme injection)

From an EOR perspective, this formula translates to:

Total Injection for Scheme/Participant - Proprietary Production for Scheme/Participant = Purchased Injection

For example, if in a particular month a participant injects 100 m^3 of propane into the EOR scheme and produces 40 m^3 of propane (after processing at the associated gas plant) from the EOR scheme, the proprietary volume will be 40 m^3 and the purchased volume will be 60 m^3 for the month.

Breakthrough Volume

Injected solvents form a miscible bank with the crude oil. Injected chase gas displaces this solvent bank and the crude oil flows to the producing wells. Solvents and chase gas can also be reproduced, along with crude oil and solution gas at various stages of the scheme. This reproduction of injected material is referred to as breakthrough.

For EOR purposes, breakthrough volume is determined by subtracting a base gas production volume from total gas production. Only injection volumes, net of breakthrough, are allowed for relief. The base gas production is determined using the following formula:

(Total Oil Production x Scheme Base GOR) / 1000

The gross breakthrough volume can be reduced by the breakthrough gas consumed (fuel and flare) in the processing plant when preparing the gas for re-injection. Fuel and flare losses may be deducted only if breakthrough gas is actually consumed in the processing plant. If purchased gas is used for plant consumption, these costs form part of the allowable costs in calculating gas royalty and there will be no reduction to the breakthrough volume. The amount of breakthrough claimed

for fuel and flare is the pro-rata share of total plant fuel and flare based on the percentage of total breakthrough volume received at the plant inlet. As an example, if 15 per cent of the plant's inlet volume is attributable to breakthrough, only 15 per cent of the plant fuel and flare losses are allowable as a reduction to breakthrough volume.

Net breakthrough volume cannot exceed total volume injected.

Base Gas-Oil Ratio (GOR)

The base GOR, used in the breakthrough volume calculation, is determined as follows:

a) The scheme solution GOR figure is submitted by the operator.

b) The Department reviews and confirms/revises the solution GOR figure based on advice received from the AEUB. This figure is rounded upward to the nearest 5.

c) The GOR in (b) is uplifted by 10 per cent. The uplifting allows ease of implementation and eliminates or reduces the need to review and make minor adjustments.

The Department provides the final uplifted solution GOR (base GOR) figure in (c) above to the operator. If the operator disagrees with this final base GOR, the operator may submit an appeal to the Department (see Subsection 5.8). The submission should outline reasons why the base GOR is not appropriate (i.e., facilities and/or operating conditions have changed, PVT study employed was in error, etc.).

Blowdown of Vertical Schemes

In most situations, no solvent or chase gas injection occurs once a scheme commences blowdown and, therefore, no eligible operating costs may be claimed. As noted in Subsection 5.5, the unamortized capital balance and carry-forward costs are eligible as long as there continues to be incremental oil production ("t" factor x gross production) from the scheme. New capital is eligible during blowdown consistent with the eligibility and incremental requirements of Subsections 2.1 and 4.2.

In some situations, an operator may continue to inject gas following the commencement of blowdown. In principle, only solvent or chase gas injected primarily for the purpose of increased incremental oil recovery is an eligible cost deduction. Injection for the purpose of gas or liquid storage is not an eligible cost. Therefore, as a general rule, no operating cost deductions are eligible once the requirement for gas injection specified in the AEUB Section 26 approval is removed or waived.

Gas injection volumes will generally remain as an eligible cost in situations where the AEUB Section 26 approval requires partial pressure maintenance through the reinjection of produced gas. In such cases, allowable injection volumes for a month are limited to the gas production volume for the same month based on the OAS.

The Department notes that additional flexibility in terms of cost deductions may be desirable and justified in some situations. The operator may apply to have additional gas injection volumes eligible during the blowdown phase. The operator will be required to show that the primary purpose of gas injection is for the recovery of incremental oil.

In all situations, royalty relief may be suspended or terminated if the Department concludes that the primary purpose of injection is for storage and not the recovery of crude oil (Subsection 4.3).

2.4 Valuation of Allowable Injectants

The value of net injected material is an allowable cost in determining EOR royalty relief. The Department uses the following concepts in establishing the valuation of allowable injectants.

Valuation of Injectants

Costs associated with net injected hydrocarbons, gas and solvents, are allowable for royalty relief. A present worth factor of 0.90 is applied to the cost of injected hydrocarbons to provide for their value upon reproduction.

Value of Gas

Injected gas is valued at the same price used to value the Gas Royalty client's (EOR scheme participant's) gas volumes. If, for Gas Royalty purposes a client elects Corporate Average Price (CAP) valuation, the price used for EOR valuation is the CAP. For clients using Reference Price, EOR gas volumes are valued using the Gas Reference Price in effect for the month in which they were injected.

Any retroactive amendment of CAP value for Gas Royalty purposes automatically triggers a recalculation of EOR royalty relief for the year. (This will occur only if a retroactive adjustment results in a change equal to or greater than 5 per cent of the client's previously filed CAP. Otherwise, retroactive adjustments are included in the current year's CAP.) If a CAP election ceases to be valid, Gas Reference Price is used to value the client's gas volumes. Reference pricing is not subject to retroactive adjustments.

Value of Ethane

Effective January 1994, injected ethane volumes are valued monthly for each EOR participant based on the following formula:

Ethane $\$/m^3$ = ($\$19.15/m^3$ x Adjustment Factor) + (Gas Reference Price \$/GJ x 18.458 GJ/m^3)

The adjustment factor is used to equate the overall value of ethane calculated using the above formula to a value equal to industry's actual cost experience for the period 1990 - 1991. This factor is currently calculated as 1.1, using unaudited data. The factor will be finalized in May 1995.

Annually, beginning January 1, 1992, the Canada GDP deflator will also be applied to the basic factor ($19.15/m^3 x Adjustment Factor) to recognize inflation.

It is intended that the above formula reflect the ethane market for EOR. Either CAPP or the Department may request a review of ethane pricing if the above formula no longer represents the market. Any change in the pricing structure developed through this review applies retroactively to the month in which the change was initiated.

Value of Other Natural Gas Liquids

Monthly reference prices minus the Regional Transportation and Storage Allowances used for Gas Royalty purposes forms the basis for the valuation for propane, butane and pentanes plus injected into EOR schemes. The value used for non-specification product is further reduced by the Fractionation Allowance.

The Regional Transportation Allowance used for each product is the one applicable to the location of the EOR scheme. Where an EOR participant also owns transportation facilities and subject to a unique transportation rate for the purposes of Gas Royalty, the same rate is used for EOR royalty relief purposes.

Proprietary Valuation

Each proprietary injectant is valued according to the following formula:

Opportunity Cost = Injectant Value - Gross Royalty + Processing Allowance

Where:

Gross Royalty is the monthly royalty value for the EOR participant's proprietary injectant GJs or volumes. It is consistent with the royalty valuation determined in Gas Royalty for the same product from the EOR participant's Injection Scheme.

Processing allowance is the allowance granted to the participant for gathering, compressing and processing the Crown's share of proprietary gas and liquids injected into an EOR scheme. The processing allowance affects the cost of injectants in two ways: it increases the opportunity cost of proprietary injectants, and is an allowable cost for breakthrough gas (see Subsection 2.5). The processing allowance is intended to cover the costs incurred for the conversion of gas into a state acceptable for injection.

For opportunity cost, processing allowance is determined as follows:

1. The Crown share of Operating Cost Allowance is the monthly gas equivalent volume (adjusted for energy content) of the Crown royalty share for the EOR participant's proprietary injectant multiplied by the applicable Unit Operating Cost Rate (UOCR). The UOCR and energy content conversion factors are discussed in detail in the Gas Royalty Principles and Procedures.

The UOCR is determined by the AEUB facility. The AEUB facility is the processing plant or gathering system at which plant gate quantities of gas and gas products from the EOR scheme are reported for Crown royalty determination.

Plus

The Crown share of Capital Cost Allowance. This is the Capital Cost Allowance allocated to the EOR participant's proprietary injectant multiplied by the participant's Corporate Effective Royalty Rate. The Capital Cost Allowance is net of custom processing. The Corporate Effective Royalty Rate is discussed in detail in the Gas Royalty Principles and Procedures. The Crown share of Capital Cost Allowance is calculated as follows:

$$\frac{\text{Total Annual Capital Cost Allowance for the EOR Participant at the AEUB Facility} \times \text{Gas Equivalent Volume of Proprietary Injectant for the Month}}{\text{Gas Equivalent Volume of Total Production for the Participant at the AEUB Facility for the Year}}$$

multiplied by the participant's Corporate Effective Royalty Rate.

The above calculation is done if the EOR participant is processing gas through owned facilities associated with the AEUB facility.

2. If the EOR participant is processing gas through non-owned facilities associated with the AEUB facility, the net custom processing fees allocated to the participant for proprietary injected volumes at the AEUB facility, multiplied by the participant's Corporate Effective Royalty Rate, is equal to the Crown share of Custom Processing Cost Allowance. (See Subsection 2.5 for definition of net custom processing fees.)

3. If an EOR participant is processing gas through both owned and non-owned facilities associated with the AEUB facility, processing allowance will be calculated as a combination of the above formulae.

Other Fluids Injected

The entire cost of injected nonhydrocarbon materials such as nitrogen (N_2), carbon dioxide (CO_2), alkalis, polymers and surfactants is allowable. The present worth factor of 0.90 is not applicable since there is no salvage value for these materials.

The operator may construct and operate a generating plant for nonhydrocarbon injectants, such as CO_2 and N_2, that is fully dedicated to the EOR scheme. The Department will allow the capital for EOR royalty relief and recognize the plant's operating expenses to be similar to purchasing the injectants. If any part of the plant's output is sold, the facility is no longer fully dedicated to the EOR scheme and, therefore, only partial capital and operating costs will be allowed for EOR relief.

Breakthrough Valuation

The valuation of breakthrough gas is on a natural gas price basis rather than on a component basis. The heating value of the breakthrough gas produced in a year is assumed to be the average heating value of the hydrocarbons injected during the same year.

The price used to value breakthrough gas is a weighted average of the value used for purchased injected gas and the net value for proprietary injected gas. The weighting between purchased and proprietary value is determined as follows:

> Breakthrough gas is assumed to reflect all injectants (solvent and chase gas) for the year. A ratio for proprietary and purchased injectants is determined based on total injectants (on a gas equivalent basis). The ratios are then applied to CAP or Gas Reference Price for purchased injected gas and the net value for proprietary injected gas. A weighted average price is then derived to value breakthrough gas.

2.5 Other Allowable Operating Costs and Allowances

Breakthrough Processing Allowance

A breakthrough processing allowance is paid on all breakthrough volumes, and limited to the total injected volume.

The allowance for each EOR participant, who is processing breakthrough gas through owned facilities associated with the AEUB facility, is calculated based on the following formula:

Allowance = (Operating Rate + Capital Rate for the AEUB facility where breakthrough gas is processed)
x Participant's Gas Equivalent Breakthrough Volume

Where:

> Operating rate is the UOCR for the AEUB facility.
>
> Capital rate is a rate per unit calculated for the AEUB facility, net of custom processing, calculated as:
>
> $$\frac{\text{Total Annual Capital Cost Allowance Allocated to EOR for the Participant at the AEUB Facility}}{\text{Total Annual Gas Equivalent Volume of Proprietary Injectant for the Participant at the AEUB Facility}}$$
>
> The participant's gas equivalent breakthrough volume is the total net gas equivalent breakthrough volume for the scheme multiplied by the EOR participant's working interest ownership percentage.

If the EOR participant is processing breakthrough gas through non-owned facilities associated with the AEUB facility, the breakthrough processing allowance is calculated as:

$$\text{Allowance} = \left(\text{Operating Rate} + \frac{\text{Annual Net Custom Processing Fees for the Participant at the AEUB Facility}}{\text{Total Annual Gas Equivalent Volume for the Participant at the AEUB Facility}}\right) \times \text{Participant's Gas Equivalent Breakthrough Volume}$$

Where:

Net custom processing fees are the total eligible custom processing fees, less the allowable operating cost on custom processed gas and gas products, paid by the EOR participant at the AEUB facility. Net custom processing fees are discussed in detail in the Gas Royalty Principles and Procedures.

Total annual gas equivalent volume is the gas equivalent volume of total production for the EOR participant at the AEUB facility for the year.

If an EOR participant is processing breakthrough gas through both owned and non-owned facilities associated with the AEUB facility, breakthrough processing allowance will be calculated as a combination of the above formulae.

If the wells for the EOR scheme are associated with more than one AEUB facility, the breakthrough processing allowance will be calculated based on the volumes actually processed at each facility. For example, if 100 units are processed at Facility 1 and another 100 units are processed at Facility 2 for a total of 200 units, only 100 units are eligible for breakthrough processing allowance at each facility.

Energy Consumed

The cost of fuel or other energy required to inject hydrocarbons or nonhydrocarbons is an allowable cost. Incremental energy required to inject water is allowed only for a water alternating gas (WAG) or a water alternating CO_2 (WACO) horizontal flood. Fuel costs are to be determined as the weighted average value of purchased and proprietary gas injected for the year. Energy costs are only eligible for injection operations. Energy costs related to production assets (i.e., submersible pumps and batteries) are ineligible.

Allowable electricity costs are usually actual costs incurred. In some situations, power companies (i.e., Alberta Power) require a contribution be paid in advance for the cost of the equipment. This payment offsets the portion of the capital cost which they feel will not be recouped from expected revenues. The difficulty is that the operator has not purchased any equipment, since the power company retains the title, and the operator has not paid for any energy use. The only method to reflect these costs in the energy charge for injection is for the power utility to reflect the capital contributions in their billing. If this is done, these capital contributions can be expensed over the planned injection phase, effective January 1, 1991. If the injection phase has been completed, the Department will review each case to determine an appropriate means of expensing these contributions.

Transportation

Two volumetric transportation rates, one for each of gas and liquids, are calculated by the Department on a scheme/participant basis as follows:

$$\text{Transportation Rate} = \frac{\text{Total Transportation Claim including In-Transit Storage Costs (1990-1992)}}{\text{Gross Volume Injected (1990-1992)}}$$

The calculated rates are applied to the scheme/participant's injected gas volume and injected liquid volumes for the next five years (1994 - 1998). Industry and the Crown will review transportation during 1998 to determine appropriate future action.

Rates will be finalized in May 1995 and will include audit adjustments to that date.

Corrosion Monitoring and Inhibition

Costs incurred to mitigate and inhibit the corrosive effects of injectants in nonhydrocarbon miscible floods and chemical floods are eligible.

Overhead Allowance

An overhead allowance that is a percentage of the total of all the above allowable operating costs and allowances plus capital amortization is provided to compensate for incremental costs not defined above (such as field operating expenses, in-house engineering and design costs, overhead, allocated head office expenses, indirect office labour, etc.). This allowance is 15 per cent for vertical EOR schemes and 25 per cent for horizontal EOR schemes.

2.6 Allocation/Recapture of Cost Allowances - Gas Royalty and EOR

Gas Royalty Simplification had a significant impact on the existing EOR royalty relief program. Processing costs for proprietary injected material were formerly claimable only under EOR. No Gas Cost Allowance was payable on these injected volumes.

Under Gas Royalty Simplification, the allocation of cost allowances will continue between EOR and non-EOR volumes.

The following describes the allocation or recapture of cost allowances.

1. Operating Cost Allowance:

As part of the Gas Royalty calculation, the Department reduces monthly Crown royalty charges by the Crown share of Operating Cost Allowances. The Crown share of Operating Cost Allowances is calculated monthly for each Gas Royalty client at each AEUB facility through which the client

gathers, compresses or processes gas and gas products. Because EOR proprietary injection volumes will also receive this allowance, it must be recaptured.

The recapture of this allowance will be as follows. For each month of the year, and for each product injected into the scheme, the Crown royalty injection credit provided will be reduced by the Crown share of Operating Cost Allowance for proprietary injected volumes (indigenous production).

The Crown share of Operating Cost Allowance will be based on the Unit Operating Cost Rate applicable to the AEUB facility. The AEUB facility is the processing plant or gathering system at which plant gate quantities of gas and gas products from the EOR scheme are reported for Crown royalty determination.

2. Capital Cost Allowance:

The Department will allocate the Capital Cost Allowance between EOR and non-EOR volumes. The Capital Cost Allowance calculated for the participant's EOR proprietary injected volumes (as detailed in Subsection 2.4) will be subtracted from the participant's total allocated Capital Cost Allowance. This calculation will be done by the Department.

3. Custom Processing Cost Allowance:

If the EOR participant is not an owner in the gas processing facilities, the net custom processing fees at the AEUB facility will be allocated between EOR and non-EOR volumes. Net custom processing fees paid by a participant (Gas Royalty client) are the eligible custom processing fees paid in the year, less the allowable operating cost on custom processed gas and gas products for the year.

The net custom fees associated with EOR proprietary injected volumes will be calculated as follows:

$$\text{Net Custom Processing Fees for the Participant at the AEUB Facility} \times \frac{\text{Participant's Proprietary Gas Equivalent Volumes at the AEUB Facility for the Year}}{\text{Total Gas Equivalent Volume for the Participant at the AEUB Facility for the Year}}$$

The above calculation will be done by the Department.

3.0 APPLICATION PROCEDURES

This section presents the procedures that operators are to follow when submitting applications for EOR royalty relief.

3.1 New Schemes

Before an application is submitted to the Department for EOR royalty relief under the Enhanced Recovery of Oil Royalty Reduction Regulation, it must be preceded by an application to the AEUB for approval under Section 26 of the Oil and Gas Conservation Act.

Application for EOR royalty relief (including a copy of the AEUB Section 26 application) should be sent to:

Senior Director, Petroleum Royalty and Incentives
Operations and Support Division
Alberta Energy
10th Floor, North Petroleum Plaza
9945 - 108 St
Edmonton AB T5K 2G6

A copy of the EOR royalty relief application should also be sent to:

Manager, Oil Department
Alberta Energy and Utilities Board
640 - 5 Ave SW
Calgary AB T2P 3G4

There are two critical dates for applicants:

EOR royalty relief, if approved, is effective either on the first day of the month the Department receives the application or injection begins, whichever is later. In order to establish an early effective date, operators may submit a brief one-page application that must be followed by a detailed submission within 120 days.

Detailed economic and technical information, as outlined below, is required as part of an application for EOR royalty relief under the Enhanced Recovery of Oil Royalty Reduction Regulation. This information is required to evaluate the proposed EOR scheme.

INFORMATION REQUIREMENTS FOR NEW SCHEMES

Economic and technical information is required for two cases:

- Base case
- Enhanced recovery case

All data must be submitted in metric units. All capital costs and operating expenses for the forecasts are expressed in constant dollars either of the year in which the application is made or the starting year of injection.

1. Scheme Area

   - Maps showing definition of scheme area(s)
   - All data to be submitted for scheme area(s) and the Crown portion only

2. Recovery

   - Initial oil-in-place
   - Base case recovery
   - Ultimate enhanced recovery case recovery
   - Net cumulative production as of injection commencement date
   - NEW oil ("n") factor
   - Tertiary production ("t") factor
   - Solution GOR

3. Production - Base Case and Enhanced Recovery Case

   - Oil production by year
   - Density and sulphur content of oil production
   - Gas production (native) for sales
   - NGL production (native) for sales
   - Reproduced gas and NGLs that are sold (base case plus tertiary only)
   - Average heating value of gas production sold
   - Average composition of NGL production sold
   - Number of production and injection wells
   - Royalty classification for gas and by-product sales

4. Operating Expenses - Base Case

   - Direct operating expenses by year for scheme
   - Direct operating expenses by year, broken down by field, plant, gathering system, etc.

5. Operating Expenses - Enhanced Recovery Case, Ineligible for EOR Relief

   - Direct operating expenses by year
   - Above expenses broken down by field, plant, gathering system, etc.

6. Injection Expenses for Hydrocarbon Miscible Flood - Enhanced Recovery Case

- Proprietary solvent (NGLs and dry gas) annual injection volume
- Purchased solvent (NGLs and dry gas) annual injection volume
- Proprietary chase gas annual injection volume
- Purchased chase gas annual injection volume
- Cost of purchased nitrogen, if used as the chase or displacing medium
- Average composition of injection NGLs
- Average heating values of all gas streams
- Proprietary gas injected, old or new, Crown or freehold
- All injection volumes to be expressed in standard surface conditions with compressibility factors provided on a total basis
- Energy requirements for hydrocarbon injection and water injection for a WAG scheme
- Transportation costs to bring injectants to the injection site
- Processing allowance (not to exceed allowable cost) for the breakthrough injection volume that does not receive EOR injection credits

7. Injection Expenses for Carbon Dioxide (CO_2) and Other NonHydrocarbon Miscible Floods - Enhanced Recovery Case

- The cost of CO_2 as supplied on a cost-of-service basis including transportation costs, if any
- As an alternative to the above, the operating expenses of a CO_2 processing facility are considered as the purchase price of the product
- Energy requirements for injecting CO_2 and water injection under a WACO scheme
- Corrosion monitoring and inhibition costs

8. Injection Expenses for Chemical Floods - Enhanced Recovery Case

- The cost of alkalis in an alkaline flood
- The cost of surfactants in a surfactant flood
- The cost of polymers in a polymer flood
- Energy requirements (if applicable) for injection of the water-chemical mix
- Corrosion monitoring and inhibition costs
- Processing allowances are not applicable

9. Capital Expenditures - Base Case and Enhanced Recovery Case

- Capital expenditures broken into broad categories as defined in Subsection 2.1
- Identification and justification of new wells to be drilled, as well as those to be converted

10. Technical Risk Analysis

- Technical risks should be described for the enhanced recovery case, and related to reservoir characteristics and geological conditions

11. Oil Prices (optional)

- Oil price forecast
- Inflation, relative growth assumptions
- Density and sulphur content of crude

12. Gas and NGL Prices (Optional)

- Price forecast for sales gas and NGLs; plant gate prices for C_2, C_3, C_4 and C_5

13. Inflation (Optional)

- General inflation forecast
- Cost index forecast (capital and operating expenses)

3.2 Scheme Enhancement

Expansion to Scheme Area

An expansion to an existing scheme area requires that an application must be submitted to the Department, and it must contain all the information requirements for a new scheme.

Revised Operating Strategy/New Capital Additions

Revised operating strategies or new capital expenditures, which continue to meet eligibility requirements and conditions of the AEUB Section 26 and the Department royalty relief approvals, do not require advanced approval by the Department. However, expenditures that arise from a change to the AEUB Section 26 approval require approval by the Department. If eligibility of new capital is in doubt, the operator may apply to the Department for an advanced ruling. Application should be made to:

Senior Manager, EOR Relief Programs
Petroleum Royalty and Incentives
Operations and Support Division
Alberta Energy
9th Floor, North Petroleum Plaza
9945 - 108 St
Edmonton AB T5K 2G6

An application under this section requires the following information:

1. Additional capital must be suitably itemized (as described in Section 2.0) and its purpose outlined. The costs of the additional capital items must be expressed in constant dollars of the year the application is made. Costs that are not eligible, such as in-house engineering and design costs, must be shown separately.

2. Copies of all correspondence with the AEUB that relate directly to the additional capital requests should be provided.

3. A map of the scheme area must be provided, identifying wells and pipelines within the scheme area. Capital additions concerning wells and/or pipelines must be highlighted on the map. Where appropriate, schematic flow diagrams should be included in the case of facilities/equipment.

4. A discussion supporting the fact that the additional capital would not be used in an optimized base case.

5. Authority For Expenditures (AFEs) should be provided.

6. Changes, if any, to the enhanced recovery production and injection profiles must be provided with volumetric balances. This would include:

   - oil production by year
   - total gas production
   - gas production (native) for sales
   - NGL production (native) for sales
   - reproduced gas and NGLs that are sold
   - number of production and injection wells
   - royalty classification for gas and by-product sales
   - average heating values of all gas streams
   - average composition of NGLs

   For injection-related expenses, the following must be provided:

   - proprietary solvent (NGLs and dry gas) annual injection volume
   - purchased solvent (NGLs and dry gas) annual injection volume
   - proprietary chase gas annual injection volume
   - purchased chase gas annual injection volume
   - average composition of NGLs
   - average heating values of all gas streams
   - incremental energy requirements for hydrocarbon injection and water injection of a WAG scheme
   - transportation costs to bring injectants to the injection site
   - processing allowance for breakthrough volumes

7. Changes, if any, to the base case production profile are to be submitted.

   The Department may waive some or all of the information requirements for scheme enhancements.

4.0 APPROVAL PROCESS

This section outlines the process for approval of EOR royalty relief for new schemes and scheme expansions. It also describes the approval process for terminating royalty relief.

4.1 New Schemes

The Department, in consultation with the AEUB, evaluates each application for royalty reduction under the Enhanced Recovery of Oil Royalty Reduction Regulation. There are three key criteria:

1. The scheme must be an enhanced recovery scheme.

2. The scheme is likely to produce more crude oil from the pool than could be produced under the base recovery scheme for that pool.

3. The costs to implement and operate the EOR scheme are significantly greater than the costs to implement and operate the base recovery scheme.

To be considered as an enhanced recovery scheme, the following criteria must be met:

1. The scheme must receive technical approval from the AEUB under Section 26 of the Oil and Gas Conservation Act.

2. The scheme must use the injection of hydrocarbons, carbon dioxide, nitrogen, chemicals or other material approved by the Minister.

The key steps followed by the Department are:

- Contact the appropriate company representatives to rectify any deficiencies in the application.

- Evaluate the application, including the tertiary "t" factor and the solution GOR (the AEUB will be consulted as necessary).

- Examine the technical risks associated with the EOR scheme (the AEUB will be consulted as necessary).

- Recommend EOR relief to the Minister if all eligibility criteria are met.

- Notify the applicant by letter of the Minister's decision. Approved schemes will be notified of the effective date of approval, the initial month of royalty relief, the new oil "n"' factor, the tertiary "t" factor and the base GOR.

In the approval, the Department may establish terms and conditions relating to the scheme. From time to time, the Department may also add to, change or delete those terms and conditions.

4.2 Scheme Enhancement

For technical and/or economic reasons, it may be desirable to invest additional capital or to revise the operating strategy for an existing scheme. The scheme may also be expanded to include areas outside the originally approved area.

Scheme revisions that result in improved economic recovery of the resource are strongly encouraged. In all cases, the Department will evaluate the eligibility of new costs associated with any scheme revision using the criteria for a new scheme. The criteria will be applied at the time of the expenditure. As an example, a capital expenditure that meets the requirements of Subsection 2.1 will be considered an eligible cost if the intention is to produce incremental oil as a direct result of the injection (current or past) of an approved material (i.e., hydrocarbons). Capital expenditures that meet the criteria of a new scheme at the time of expenditure do not require advanced capital approval from the Department. However, all capital expenditures will be reviewed by the Department to ensure their eligibility. Advanced rulings will be provided upon the operator's request if eligibility is in doubt.

Expansion to an existing scheme area requires that an application be submitted to the Department. If the new area meets all the criteria of a new scheme and is subsequently approved, it will be rolled into the existing scheme. The Department will administer only one EOR scheme per pool.

4.3 Scheme Suspension or Termination

Termination of the AEUB Section 26 approval will, in all instances, result in the EOR royalty relief being terminated.

Termination and/or Suspension by Operators

An operator may request suspension or termination of royalty relief for a scheme, for technical or economic reasons, before the end of the planned scheme life.

Termination and/or Suspension of Royalty Relief

In the following circumstances, the Department may choose to suspend or terminate royalty relief for an EOR scheme:

- If the Department concludes that the primary function of an EOR scheme is not the recovery of crude oil. This refers to situations where the scheme's main function has become gas and/or liquid storage.
- Operator fails to submit the annual report of estimated costs by the December 31 deadline.
- Operator fails to submit the annual report of actual costs by the June 30 deadline.

- Operator fails to submit relevant technical or other information to the Department for scheme evaluation within the time period specified in the request.
- The Department concludes that the EOR scheme is not being operated in accordance with the terms and conditions of the approval.
- The Department concludes that the scheme has finished, or the "t" factor for the scheme is zero.

Termination and/or Suspension of Royalty Relief to an Owner

In the following circumstances, the Department may choose to suspend or terminate royalty relief for a participant's portion of the EOR scheme:

- The participant has failed to provide the information requested within the time period specified.
- An amount payable by the participant is not paid within 120 days of notification.

5.0 ADMINISTRATION OF APPROVED SCHEMES

The Petroleum Royalty and Incentives Branch of the Operations and Support Division administers the EOR royalty relief program under the Enhanced Recovery of Oil Royalty Reduction Regulation.

Section 6.0 outlines the procedures for reporting annual estimated and actual costs. Schedules to be completed by operator/participants must be submitted to:

Senior Manager, EOR Relief Programs
Petroleum Royalty and Incentives
Operations and Support Division
Alberta Energy
9th Floor, North Petroleum Plaza
9945 - 108 St
Edmonton AB T5K 2G6

5.1 Annual Cost Estimates

Upon notifying the operator that the Department has approved the scheme for EOR royalty relief, the operator must file estimates of the scheme's allowable capital and operating costs from the initial month of authorized relief to the end of the calendar year. For each subsequent operating calendar year, the operator must file an estimate of capital and operating costs with the Department no later than December 31 before the relief year. Estimates must be received by October 31 of the preceding year in order to be reflected in the January royalty reductions. Annual cost estimates must be filed using schedules 1 and 11. See Subsections 6.1 and 6.5 for detailed filing requirements.

5.2 Method of Providing Royalty Relief

The Department uses the applicable par price for the month in which the estimate or revised estimate is processed to calculate a monthly relief volume. The calculated volume remains fixed until the estimate is revised by the operator or recalculated by the Department. The interim monthly relief that is granted is the lesser of the following:

1. [(Annual Estimated Costs x Crown Interest x Royalty Rate) / 12] / Oil Par Price*

   or

2. [(Annual Estimated Crown Production x Royalty Rate x "t" factor) / 12]

*Where Oil Par Price is the applicable oil par price for the month in which the estimate or revised estimate is processed.

The operator deducts this volume from the royalty calculated as prescribed in the Petroleum Royalty Regulation.

This calculation is reviewed by the Department at least twice during the year to minimize the over/under-payment of relief. The calculation is also reviewed and adjusted if the actual par price deviates more than 10 per cent from the par price used in the calculation. Any amendments to the estimate also trigger a recalculation.

5.3 Tertiary "t" Factor

Royalty reductions are applied only to the Crown's share of incremental production. Incremental production is that portion of the scheme production that would not have been realized from the base case scheme. In practice, the incremental production volume is determined through the application of a constant percentage ("t" factor) to the gross production from the scheme. The "t" factor is defined as the lesser of either 0.9 or the difference between the recoverable oil reserves estimated for the EOR scheme and the recoverable reserves from the base case scheme, divided by the remaining recoverable oil reserves for the EOR scheme, as established by the Department from time to time.

For an EOR scheme approved after May 31, 1990, the "t" factor is the lesser of 0.9 and the result of the following formula:

$$\text{"t" Factor} = \frac{\text{Incremental Tertiary Reserves over Scheme Life}}{\text{Remaining Recoverable Reserves at Start of Tertiary Flood}}$$

The start of the tertiary flood date is consistent with the commencement of the royalty relief date.

For an EOR scheme approved before June 1, 1990, the "t" factor is the lesser of 0.9 and the result of the following formula:

$$\text{"t" Factor} = \frac{\text{Incremental Tertiary Reserves over Scheme Life}}{\text{Remaining Recoverable Reserves at June 1, 1990}}$$

It will be the operator's responsibility to submit applications to the Department for "t" factors for new EOR schemes, and any subsequent revisions to a scheme as to size of established reserves. The operator will be advised of the "t" factor that the Department has established for the scheme. Oil migration will be considered in determining the remaining recoverable value when reservoirs are partially miscible flooded as in the case of staged development of large horizontal floods.

The Department may request the operator to review the "t" factor for a scheme with regard to the scheme's current performance, its projected performance and the appropriateness of the established reserves. The "t" factor will be revised by the Department to be consistent with any changes to scheme reserves, and will be applied on a forward-only basis from the effective date of the reserve change.

5.4 Actual Annual Costs

No later than June 30 of the year following the reporting year, operators (participants in the case of nonhydrocarbon schemes) must file the required information with the Department. Upon verification by the Department, an interim royalty relief adjustment is made.

Participants who hold a reporting interest at the end of the year (December 31) are considered to be the holder of record for the year and will be responsible for settling any royalty relief differences. The current holder of a reporting interest may also be responsible for any historic liability on annual reporting, revisions or audit adjustments.

Actual annual costs must be filed using Schedules 2, 5, 6 and 13 (see Subsections 6.2, 6.3, 6.4 and 6.6, respectively, for detailed filing requirements). Failure to file the statement of actual costs by the required date will result in a penalty (Subsection 5.9), and may result in suspension or termination of royalty relief (Subsection 4.3).

5.5 Adjustments to Royalty Relief

Unamortized Capital Base

The unamortized capital base will not be completely written off if royalty relief is terminated, or if the product of "t" factor multiplied by the gross oil production equals zero. However, in some situations the capital balance may diminish to a very low amount over time. As it would not be cost-effective for operators/participants to carry the asset base on their books, the operator/participant may apply to the Department to fully amortize the remaining capital balance. The Department may also decide, in some circumstances, to fully amortize the remaining capital balance.

Carry-Forward Costs

If in any year the allowable costs exceed the total incremental revenue (given by Crown interest in "t" factor times gross production times par price) from the production of crude oil for the year, the excess shall be added to the allowable costs for the subsequent calendar year.

If carry-forward costs exist after the injection has stopped, royalty relief will be provided on these costs as long as the "t" factor times gross oil production is greater than zero.

Interest on Royalty Relief Variances

The rate for calculating interest is 1 per cent greater than the Alberta Treasury Branch prime rate as of the first day of each month. Interest will not be charged/payable for a client/scheme if the interest calculated is less than $100. No interest is payable by the Crown for relief underpayments relating to the years before 1994. No interest will be charged by the Crown before February 13, 1992.

Interest is calculated in the following situations:

1. Estimate to Actual - If a participant's share of the estimated EOR royalty relief provided throughout the year for all approved schemes varies from the participant's initial actual relief calculation by more than 10 per cent, interest is calculated on the full variance from January 1 of the year after the relief year until the date of repayment or cheque requisition by the Department.

2. Estimate to Actual - If a participant's share of the estimated EOR royalty relief provided throughout the year for all approved schemes varies from the participant's initial actual relief calculation by 10 per cent or less, interest is calculated on the full variance from July 1 of the year after the relief year and continues until the date of repayment or cheque requisition by the Department.

3. Actual to Revised Actual - Interest is calculated on the full variance between a participant's actual relief and revised actual relief for a scheme. This calculation commences on July 1 of the year after the relief year and continues until the date of repayment or cheque requisition by the Department.

4. Actual to Audit - Interest is calculated on the full variance between a scheme participant's actual relief and audited relief. This calculation commences on July 1 of the year after the relief year and continues until the date of repayment or cheque requisition by the Department.

Gas Royalty reporting changes that result in changes to EOR royalty relief will be incorporated into the EOR calculation at a minimum of once a year until close-out for the year occurs within the Gas Royalty Branch.

5.6 Audit

Section 39 of the Mines and Minerals Act empowers the Department to recalculate royalty within four years after the end of the calendar year in which the Crown's royalty share was deliverable to the Crown. If the audit is initiated in the fourth year, the Department has one additional year to complete the audit.

5.7 Issue Resolution Process

These guidelines describe existing EOR policies. The operator or participants may request a review of any decision made under these guidelines.

Requests should be directed to:

Senior Director, Petroleum Royalty and Incentives
Operations and Support Division
Alberta Energy
10th Floor, North Petroleum Plaza
9945 - 108 St
Edmonton AB T5K 2G6

5.8 Appeal Process

The operator or participants may appeal any decision made by the operating division under the process described in Subsection 5.7. See Information Letter 91-20 for further information.

Appeals should be directed to:

Director, Appeals
Royalty and Tenure Policy Branch
Policy Division
Alberta Energy
12th Floor, North Petroleum Plaza
9945 - 108 St
Edmonton AB T5K 2G6

5.9 Provisions to Enforce Compliance

The Department will assess penalties on those participants who are responsible for late filing of royalty relief data. Responsibility is identified according to Departmental records.

The Department has no authority to reverse a late filing penalty unless the penalty was levied in error. Persons responsible for filing reports may avoid late filing penalties only if:

- before the due date of the report, they inform the Department of their inability to file on time and the reason; and

- the Department is satisfied that the inability is due to circumstances beyond the control of the participant who is required to furnish the report.

For EOR royalty relief, these penalties will be applied to the those participants who are responsible for filing actual cost submissions that were due June 30. The penalty is $1,000 for each month or part thereof for which the filing is late.

Where an audit or examination has been conducted by the Department for relief years commencing January 1, 1994, and the result is an overpayment of relief, the Department may charge a penalty equal to 10 per cent of the excess relief paid to the EOR participant. Where, after being notified of receiving excess relief, the participant fails to ensure that the same or similar cause does not result in excess relief in a subsequent year for the same scheme or another scheme, the Department may impose a penalty up to 50 per cent of the excess relief in respect of the subsequent year. The Department may also impose a penalty up to 50 per cent of a participant's excess relief in a subsequent year, if the cause for the excess is similar or the same as in the notice, and the cause is attributable to the operator.

5.10 Rights and Assurances of EOR Participants

The principles supporting the rights and assurances of EOR participants will be consistent with those established for Gas Royalty, and will be considered in the overall control evaluation.

6.0 EOR REPORTING PROCEDURES

The operator, and in some situations the participant, of each EOR royalty relief scheme must provide data to the Department to support the calculation of relief. Estimated cost filings are required before the start of the year, and actual cost filings are required by June 30 of the following year. The following describes the basic requirements for each filing:

Estimated Costs

- Required schedules:
  - Schedule 1 (estimated summary cost schedule)
  - Schedule 11 (estimated oil production)
- Due date is December 31 before the reporting year. If the estimates are to be reflected in the relief provided beginning in January of the reporting year, estimates must be submitted by October 31 of the previous year.
- Filed only by the operator of the scheme.
- No revised estimates will be accepted after September 30 of the reporting year.

Actual Costs

- Required schedules:
  - Schedule 2 (capital expenditure summary)
  - Schedule 5 (nonhydrocarbon fluids injected)
  - Schedule 6 (consumed energy summary)
  - Schedule 13 (breakthrough fuel and flare volume)
- Due date is June 30 following the reporting year.
- Filed by the operator of the scheme. However, for approved nonhydrocarbon EOR schemes, each participant must file a Schedule 5. Scheme participants must disclose any grants and/or incentives received from a government in Schedule 2.
- As a result of EOR Simplification, Schedules 1, 3, 4, 7, 8, 9, 11, 12 and 13 (complete) are no longer required (based on March 1992 Conventional EOR Royalty Guidelines). Refer to Section 2.0 for the 1994 business rules on valuing injectants (Schedules 3 and 4), transportation costs (Schedule 7), and breakthrough processing allowance (Schedule 8). The March 1992 guidelines outline details on royalty relief calculation (Schedule 1), carry-forward cost calculation (Schedule 9), tertiary royalty calculation (Schedule 11), and breakthrough valuation (Schedule 12). Subsection 7.1 provides a detailed example of royalty relief calculation.
- Nil schedules are not required.

Relief is provided on an estimated basis throughout the year, and revised to actual after the end of the year.

6.1 Estimated Cost Summary–Schedule 1

Purpose

Schedule 1 is used by the operator to report estimated costs for the EOR scheme in the upcoming year. This cost data will be used by the Department to calculate the maximum estimated royalty relief payable in that year.

The due date for Schedule 1 is December 31 before the reporting year. If the estimates are to be reflected in the relief beginning January of the reporting year, Schedule 1 must be received by October 31 of the previous year. No amendments will be accepted after September 30 of the reporting year.

COMPLETING SCHEDULE 1

Field	Field Name
1	Scheme The name of the enhanced oil recovery scheme as approved by the AEUB.
2	Scheme ID The Injection Scheme ID assigned to all the production/injection wells in the EOR scheme.
3	For the Estimate Year Ending Dec. 31, ---- The year the estimated costs are expected to be incurred.
4	Operator The complete corporate or individual name of the operator of the scheme.
5	Operator ID The identifier assigned to the operator of the scheme.
6	Unamortized Balance, January 1 The unamortized capital costs for the scheme as at January 1 of the reporting year. The opening balance must equal the closing balance of the previous year. New schemes will have an opening balance of $0.
7	Additions Total estimated capital additions for the reporting year.

OPERATING COSTS

Field	Field Name
8	Hydrocarbons Injected

The total estimated cost of all hydrocarbons injected. The operator may use his own price forecast for injectants, or price forecasts provided by the Department.

9	Breakthrough Value

The breakthrough volume is estimated and valued. The value is determined by the gas price forecast used in Field 8.

10	Nonhydrocarbon Fluids Injected

Total estimated cost of injected nonhydrocarbon fluids.

11	Consumed Energy

Total estimated claim for consumed energy. The value of fuel gas is determined by the gas price forecast used in Field 8.

12	Transportation Costs

Total estimated claim for transportation costs.

13	Annual Processing Allowance

Total estimated processing allowance for breakthrough volumes.

14	Carry-Forward Costs

Carry-forward costs for the scheme from the previous year.

15	Contact Person

The name of the person to whom inquiries can be directed regarding data.

16	Date Prepared

The year, month and day that this schedule was prepared or amended.

17	Telephone

The telephone number of the contact person from Field 15.

PROCESS

The above information is used by the Department in calculating the total estimated costs for the scheme. To calculate the estimated royalty relief, the Department will use the estimated production from Schedule 11, the par price set by the Department in the month the estimate is processed, and the average oil royalty rate to date for the scheme in the current year. For amendments and the mid-year departmental review, the Department will use actual production, par prices, royalty rates, and actual relief received to date in calculating revised estimated relief. The Department will notify the operator of any changes to the monthly maximum relief volume as a result of a new or revised relief estimate.

Alberta
ENERGY

EOR - ESTIMATED COSTS SUMMARY
SCHEDULE 1

SCHEME 1		SCHEME ID # 2	FOR THE YEAR ENDING DECEMBER 31, ____ 3
OPERATOR 4		OPERATOR ID 5	

COST CATEGORY	$
Unamortized Capital, January 1	6
Capital Additions	7
Hydrocarbons Injected	8
Breakthrough Value	9
Nonhydrocarbons Injected	10
Consumed Energy	11
Transportation Costs	12
Annual Processing Allowance	13
Carry-Forward Costs	14

CONTACT PERSON 15	DATE PREPARED 16	TELEPHONE 17

6.2 Capital Expenditure Summary--Schedule 2

Purpose

Schedule 2 details capital expenditures for the relief year.

A completed actual capital expenditures Schedule 2 must contain information relating to the eligible capital claimed for the reporting year.

COMPLETING SCHEDULE 2

Field **Field Name**

1 Scheme

The name of the enhanced oil recovery scheme as approved by the AEUB.

2 Scheme ID

The Injection Scheme ID assigned to all the production/injection wells in the EOR scheme.

3 For the Calendar Year Ending Dec. 31, ----

The year the capital expenditures were incurred.

4 Operator

The complete corporate or individual name of the operator of the scheme.

5 Operator ID

The identifier assigned to the operator of the scheme.

6 Capital Expenditure Category Code

Identify the defined category of expenditure according to the following:

Category Code	Category Description
1A	Development production well (includes completion and tie-in)
1B	Development injection well (includes completion and tie-in)
2A	Well conversion or reactivation
2B	Re-perforation/Stimulation/Cement Squeeze, etc.
2C	Other major workover expenditures

Field	Field Name

6 Capital Expenditure Category Code (Continued)

Category Code	Category Description
3A	EOR injection compressors
3B	Other EOR injection system facilities
4A	Production and fluid handling facilities
4B	Specific water production/disposal and water handling facilities
5	EOR generating facilities for nonhydrocarbon displacement fluids
6	Storage facilities (on site) for EOR injection fluids
7A	Production pipelines
7B	Specific water production pipelines
7C	EOR injection pipelines
7D	Water injection and supply pipelines
8	Pollution control equipment
9	Water injection system facility expansion
10	Other approved incremental capital expenditures

For capital expenditures that are not easily separated on the AFE, more than one category may be chosen. With the exception of category code 10, codes are consistent with the defined cost list in Subsection 2.1.

7 Well/Facility Name and Legal Location

For capital expenditures related to the injection facility, the facility name and identifier.

For capital expenditures related to wells, batteries, etc., the legal location of the capital item including the legal subdivision (LSD).

8 Description and Details of Capital Expenditure

A description and purpose of the capital expenditure, as it relates to the EOR scheme. Information should be consistent with the AFE.

9 Authority for Expenditure (Identifier)

The AFE or internal reference number used to identify the expenditure.

10 Amount

The dollar value of the eligible capital expenditure described in Field 8.

Information to be provided in Fields 6 to 10 may be continued or provided in its entirety, on a separate page.

Examples for Fields 6 to 10:

Example One
Drill, complete and tie-in an infill eligible and incremental producer located in LSD 2-6-16-10 W5M at a cost of $1.5 million. Approval to drill the well was authorized by AFE #22222.

Field 6 = 1A
Field 7 = 2-6-16-10 W5M
Field 8 = Drill, complete and tie-in. Well completes existing solvent injection pattern Z.
Field 9 = 22222
Field 10 = 1,500,000

Example Two
Acid stimulation miscible/water injector 10-10-10-10 W5M. Cost was $40 thousand and authorization by AFE #33333.

Field 6 = 2B
Field 7 = 10-10-10-10 W5M
Field 8 = Workover (acid stimulate) conducted to increase injectivity in order to balance voidage from pattern H.
Field 9 = 33333
Field 10 = 40,000

Example Three
Installation of a new test separator and an expanded header for the 4-12-10-10 W5M header building. Cost is $250 thousand authorized by AFE #44444.

Field 6 = 4A
Field 7 = 4-12-10-10 W5M
Field 8 = Installation of new test separator and expansion of header. Increased production volumes with the drilling of miscible flood producers 10-12 and 2-11.
Field 9 = 44444
Field 10 = 250,000

Example Four
Convert existing producer 2-2-8-10 W5M to injection. Costs are $200,000 to tie-in and $150,000 for conversion costs (including casing inspection logs and coated tubing). AFEs 55555 and 66666 provide authorization.

Field 6 = 2A
Field 7 = 2-2-8-10 W5M
Field 8 = Conversion and tie-in costs. Addition of new pattern to EOR scheme.
Field 9 = 55555, 66666
Field 10 = 350,000

11 Total Capital Expenditures

The sum of all amounts in Field 10. If more than one Schedule 2 or a separate page is required to be completed, the total of all schedules should be entered on the last page.

12 Less Grants

The amount of any government grant(s) and/or incentives received for the purpose or construction of capital additions. The source of the grant and/or incentive is to be specified.

13 Total Net Capital Additions

Field 11 minus Field 12.

14 Date Prepared

The year, month and day that the schedule was prepared or amended.

15 Page of

The number of this page and the total number of pages filed for capital additions.

PROCESS

The Department will review the expenditures to ensure eligibility. Additional information or clarification from the operator may be requested. All claimed eligible capital costs are subject to audit to verify their existence, valuation and consistency with filed information.

Eligible capital expenditures will be used in the calculation of actual EOR relief for the year. Each participant will be allocated a share of the total capital expenditure based on its working interest ownership.

Each participant's unamortized capital balance is calculated as:

	Unamortized Balance, January 1	Equal to its unamortized balance for December 31 of the preceding year
+	Capital Additions	Total Capital Additions (Schedule 2) x Participant's working interest ownership in the scheme
-	Amortization @ 30 per cent	30 per cent (Unamortized Balance, January 1 + Capital Additions)
=	Unamortized Balance, December 31	

Each participant's amortization is used in the calculation of its actual EOR royalty relief for the year.

If a participant's interest in the EOR scheme changes during the reporting year, its unamortized capital balance will be adjusted to reflect the change in ownership as if it had taken place at January 1 of the reporting year.

For schemes that commenced during the reporting year, capital amortization is calculated as 30 per cent of:

$$\text{(Participant's share of total capital additions)} \times \frac{12 - (\text{month of commencement} - 1)}{12}$$

Alberta

ENERGY

EOR - CAPITAL EXPENDITURE SUMMARY

SCHEDULE 2

SCHEME 1	SCHEME ID # 2 FOR THE YEAR ENDING DECEMBER 31, ___3
OPERATOR 4	OPERATOR ID 5

CAPITAL EXPENDITURE CATEGORY CODE	WELL/FACILITY NAME & LEGAL LOCATION	DESCRIPTION AND DETAILS OF CAPITAL EXPENDITURE	AUTHORITY FOR EXPENDITURE (IDENTIFIER)	AMOUNT $
6	7	8	9	10

TOTAL AMOUNT $ 11	LESS GRANTS $ 12	TOTAL NET CAPITAL ADDITIONS $ 13

DATE PREPARED: 14	PAGE ___ OF ___ 15

6.3 Nonhydrocarbon Fluids Injected--Schedule 5

Purpose

Schedule 5 - Nonhydrocarbon Fluids Injected details monthly injection into nonhydrocarbon EOR schemes. Each participant holding a working interest in a nonhydrocarbon EOR scheme must file a Schedule 5 to be able to receive relief for the cost of these injectants.

COMPLETING SCHEDULE 5

Field	Field Name
1	Scheme
	The name of the enhanced oil recovery scheme as approved by AEUB.
2	Scheme ID
	The Injection Scheme ID assigned to all the production/injection wells in the EOR scheme.
3	For the Calendar Year Ending Dec. 31, ——
	The year in which the nonhydrocarbons were actually injected.
4	Participant
	The complete corporate or individual name of the client filing this schedule.
5	Participant ID
	The identifier assigned to the participant of the scheme.
6	Material
	Carbon dioxide (CO_2) or nitrogen (N_2). Approval from the Department is required before reporting any other material.
7	Volume
	The volume of nonhydrocarbon fluids injected in thousand cubic metres by month and totalled for the year.

Field	Field Name
8	Cost

If nonhydrocarbons were supplied on a cost-of-service basis, report this as the cost of injectants.

Transportation costs to the injection site are eligible and should be included in the cost. If a working interest is held in a nonhydrocarbon generating plant, the share of the plant's operating expenses (excluding depreciation and finance charges) incurred to produce the participant's share of the injectants will be viewed as the cost of purchasing the injectants.

Report the monthly costs and the total for the year.

9 Date Prepared

The year, month and day that this schedule was prepared or amended.

PROCESS

Each participant's reported nonhydrocarbon fluid injection costs are used in the calculation of its actual EOR royalty relief for the year.

Alberta

ENERGY

EOR - NONHYDROCARBON FLUIDS INJECTED

SCHEDULE 5

SCHEME 1	SCHEME ID # 2	FOR THE YEAR ENDING DECEMBER 31, ___3
PARTICIPANT 4	PARTICIPANT ID 5	

MATERIAL (CHECK ONE) 6 CO_2 _____ N_2 _____ OTHER _____

	VOLUME * $10^3 m^3$	COST $
JANUARY	7	8
FEBRUARY		
MARCH		
APRIL		
MAY		
JUNE		
JULY		
AUGUST		
SEPTEMBER		
OCTOBER		
NOVEMBER		
DECEMBER		
TOTAL		

** MEASURED AT STANDARD SURFACE CONDITIONS*

DATE PREPARED 9

6.4 Consumed Energy Summary--Schedule 6

Purpose

The cost of energy consumed for injection is eligible for royalty relief. Each participant's share of fuel gas will be valued using the weighted average value of purchased and proprietary gas injected by the participant for the year. The total electricity cost will be allocated to each participant based on its working interest ownership in the EOR scheme.

COMPLETING SCHEDULE 6

Field	Field Name
1	Scheme The name of the enhanced oil recovery scheme as approved by the AEUB.
2	Scheme ID The Injection Scheme ID assigned to all the production/injection wells in the EOR scheme.
3	For the Calendar Year Ending Dec. 31, --- The year in which the energy was consumed for injection.
4	Operator The complete corporate or individual name of the operator of the scheme.
5	Operator ID The identifier assigned to the operator of the scheme.
6	Fuel Gas - Volume The eligible volume of fuel gas consumed for injection for each month and totalled for the year. Record the volume in thousand cubic metres.
7	Fuel Gas - GJ The eligible quantity of fuel gas consumed for injection reported in Field 6 converted to its gigajoule equivalent by month and totalled for the year.

Field	Field Name
8	Electricity Cost

The eligible cost of electricity consumed for injection each month and totalled for the year. If monthly calculation of electricity cost is not easily determined, report annual cost against December only. For capital contribution, refer to Subsection 2.5.

9	Date Prepared

The year, month and day that this schedule was prepared or amended.

PROCESS

Actual consumed energy costs are used in the calculation of actual EOR royalty relief for the year. Each participant is allocated a share of the total consumed energy costs based on its working interest ownership.

Alberta

ENERGY

EOR - CONSUMED ENERGY SUMMARY

SCHEDULE 6

SCHEME	1	SCHEME ID # 2	FOR THE YEAR ENDING DECEMBER 31, ___3
OPERATOR	4	OPERATOR ID	5

	FUEL GAS VOLUME 10^3 m^3	FUEL GAS GJ	ELECTRICITY COST $
JANUARY	6	7	8
FEBRUARY			
MARCH			
APRIL			
MAY			
JUNE			
JULY			
AUGUST			
SEPTEMBER			
OCTOBER			
NOVEMBER			
DECEMBER			
TOTAL			

DATE PREPARED	9

6.5 Estimated Oil Production--Schedule 11

Purpose

Estimated oil production data are required annually by the Department to calculate estimated tertiary revenue. The production volumes reported should consider current scheme performance and not just reiterate the forecast prepared at the time of original scheme application.

COMPLETING SCHEDULE 11

Field	Field Name
1	Scheme

The name of the enhanced oil recovery scheme as approved by AEUB.

2	Scheme ID

The Injection Scheme ID assigned to all the production/injection wells in the EOR scheme.

3	For the Calendar Year Ending Dec. 31, ----

The year the estimated production is expected to occur.

4	Operator

The complete corporate name of the operator of the scheme.

5	Operator ID

The identifier assigned to the operator of the scheme.

6	Total Oil Production

The estimated oil production for each month of the reporting year and totalled for the year. If unable to accurately determine monthly estimates, complete only the total.

7	Date Prepared

The year, month and day that this schedule was prepared or amended.

PROCESS

The Department will use Schedule 11 data to calculate estimated tertiary royalty for the reporting year as follows:

Total Oil Production (from Schedule 11)

x

Estimated Par Price (the oil par price for the month in which the estimate is processed will be used as the forecast for the year)

x

"t" Factor (the "t" factor assigned by the Department to the EOR scheme)

x

Crown Interest (the overall Crown interest in the EOR scheme)

x

Estimated Royalty Rate (average royalty rate for the current year)

Alberta

ENERGY

EOR - ESTIMATED OIL PRODUCTION

SCHEDULE 11

SCHEME	1	SCHEME ID # 2	FOR THE YEAR ENDING DECEMBER 31, ____3
OPERATOR	4	OPERATOR ID	5

MONTH	TOTAL OIL PRODUCTION (m^3)
JANUARY	6
FEBRUARY	
MARCH	
APRIL	
MAY	
JUNE	
JULY	
AUGUST	
SEPTEMBER	
OCTOBER	
NOVEMBER	
DECEMBER	
TOTAL	

DATE PREPARED	7

6.6 Breakthrough Fuel and Flare Volume--Schedule 13

Purpose

The purpose of this schedule is to calculate the net breakthrough volume for the scheme.

This information is required for actual cost submissions. All data required to perform this calculation are available to the Department with the exception of the breakthrough fuel and flare volume.

Volumes of net breakthrough gas will be allocated to participants on the basis of working interest ownership.

COMPLETING SCHEDULE 13

Field	Field Name
1	Scheme
	The name of the enhanced oil recovery scheme as approved by the AEUB.
2	Scheme ID
	The Injection Scheme ID assigned to all the production/injection wells in the EOR scheme.
3	For the Calendar Year Ending Dec. 31, —
	The year in which the breakthrough fuel and flare gas was consumed.
4	Operator
	The complete corporate or individual name of the operator of the scheme.
5	Operator ID
	The identifier assigned to the operator of the scheme.
6	Scheme GOR
	The Department-approved base gas-oil ratio (GOR). Operators have been provided with GORs by the Department. Contact the Department for any questions regarding the GOR.

Field	Field Name
7	Breakthrough Fuel and Flare - 10^3m^3

The breakthrough gas consumed at the gas plant for fuel and flaring each month. Fuel and flare losses may be deducted from the volume of breakthrough gas before its valuation only if breakthrough gas is actually used for consumption in the processing plant. If purchased gas is used for plant consumption, these costs form part of the allowable costs within Gas Royalty and there will be no reduction to the breakthrough volume.

Report the monthly breakthrough fuel and flare volume and the total for the year in thousand cubic metres.

8 Date Prepared

The year, month and day that this schedule was prepared or amended.

PROCESS

Net Breakthrough Gas (10^3m^3) =
Gross Breakthrough Gas minus Breakthrough Fuel and Flare

Where Gross Breakthrough Gas is calculated as:

Total Gas Production from the EOR scheme
minus Base Gas Production from the EOR scheme

Where Base Gas Production is calculated as:

$$\frac{\text{Total Oil Production from the EOR scheme} \times \text{Scheme Base GOR}}{1000}$$

All of the above calculations are performed on a monthly basis.

Alberta
ENERGY

EOR - BREAKTHROUGH FUEL AND FLARE VOLUME

SCHEDULE 13

SCHEME	1	SCHEME ID # 2	FOR THE YEAR ENDING DECEMBER 31, ___3
OPERATOR	4	OPERATOR ID 5	SCHEME GOR 6

	BREAKTHROUGH FUEL & FLARE 10^3 m^3
JANUARY	7
FEBRUARY	
MARCH	
APRIL	
MAY	
JUNE	
JULY	
AUGUST	
SEPTEMBER	
OCTOBER	
NOVEMBER	
DECEMBER	
TOTAL	

DATE PREPARED	8

7.0 CALCULATION OF EOR ROYALTY RELIEF

The following data and process is used in the calculation of actual and estimated EOR royalty relief for each participant. For details on business rules and cost eligibility, administration, and reporting requirements refer to Sections 2.0, 5.0 and 6.0.

	Value of Hydrocarbons Injected
Less:	Breakthrough Value
Subtotal	(Zero If Negative)
Less:	Present Worth @ 10%
Subtotal	
Plus:	Nonhydrocarbon Fluids Injected
Plus:	Consumed Energy
Plus:	Transportation
Plus:	Breakthrough Processing Allowance
Plus:	Capital Amortization
	Unamortized Balance at January 1
	Plus: Additions
	Subtotal
	Multiply By 30% = Capital Amortization
Subtotal	
Plus:	Overhead Allowance - 15% for Vertical or 25% for Horizontal Schemes
Equals:	Total Costs Before Crown Interest
Times:	Crown Interest
Subtotal	
Plus:	Carry-Forward Costs
Equals:	Total Allowed Costs

Royalty Relief Equals The Lesser Of:

Total Allowed Costs x Oil Royalty Rate

OR

EOR Participant's Working Interest Ownership x Tertiary Royalty*

*Tertiary Royalty = Total Scheme Oil Production x Oil Par Price x "t" Factor x Crown Interest x Oil Royalty Rate

7.1 Detailed Example

General Assumptions

- Participant has 100 per cent working interest in the EOR scheme
- Crown interest is 100 per cent
- Tertiary factor ("t" factor) for the EOR scheme is 0.75
- All data and calculations are annual

Cost Assumptions

- Overhead allowance is 15 per cent (vertical scheme)
- Unit Operating Cost Rate (gas processing) is $\$10/10^3m^3$
- Capital Cost Rate (gas processing) is $\$10/10^3m^3$
- Transportation costs:
  Gas - $\$7.50/10^3m^3$
  NGLs - $\$5.00/m^3$
- Fuel gas consumed:
  $125\ 10^3m^3$ (5,000 GJs)
- Capital costs:

Unamortized balance, January 1	$1,000,000
Capital addition	$ 250,000
Total capital	$1,250,000
Amortization @ 30%	$ 375,000

- Corporate Effective Royalty Rate is 20 per cent
- No carry-forward costs

Price and Royalty Rate Assumptions

Product	Reference/Par Price	Royalty Rate (%)
Gas	$2.00/GJ	25%
Propane	$\$75/m^3$	30%
Butane	$\$90/m^3$	30%
Pentane	$\$120/m^3$	35%
Crude Oil	$\$120/m^3$	25%

Production and Injection Volume Assumptions

Product	Total Scheme Injection	Total Scheme Production	Injected Proprietary	Injected Purchased
Gas (GJs)	100,000	70,000	70,000	30,000
Gas (10^3m^3)	2,500	1,750	1,750	750
Propane (m^3)	5,000	4,000	4,000	1,000
Butane (m^3)	3,000	2,500	2,500	500
Pentane (m^3)	1,000	1,500	1,000	0
Crude Oil (m^3)		40,000		
Net Breakthrough Volume (10^3m^3)		2,000		

i) **Valuation of Hydrocarbons Injected**

(a) **Proprietary Valuation**

Opportunity Cost = Injectant Value - Gross Royalty + Processing Allowance

Where:

Injectant Value = Injection Quantity x Price

Gross Royalty = Injectant Value x Royalty Rate

Processing allowance is the sum of the Crown's share of Operating Cost and Capital Cost Allowances. The Crown's share of Operating Cost Allowance is equal to the Crown royalty share (royalty rate x product volume) multiplied by the Unit Operating Cost Rate ($10/10^{3}m^3 in this example) and multiplied by the energy adjusted gas equivalent factor. The Crown's share of Capital Cost Allowance is equal to the gas equivalent volume of each product multiplied by the capital cost rate ($10/10^{3}m^3 in this example) and multiplied by the Corporate Effective Royalty Rate.

The following conversion factors are used to determine gas equivalent volumes, and energy adjusted gas equivalent volumes. These factors are consistent with those used for Gas Royalty purposes.

Product	Gas Equivalent Factor (10^3m^3)	Energy Adjusted Gas Equivalent Factor
Gas (10^3m^3)	1.00000	1.00000 x 1.00 = 1.00000
Propane (m^3)	0.27201	0.27201 x 2.41 = 0.65554
Butane (m^3)	0.23331	0.23331 x 3.12 = 0.72793
Pentane (m^3)	0.20570	0.20570 x 3.83 = 0.78783

Proprietary valuation is calculated as follows:

Product	Injectant Value		Gross Royalty	Processing Allowance*		Proprietary Value
Gas	$140,000	-	35,000	+ 7,875	=	$112,875
Propane	300,000	-	90,000	+ 10,043	=	$220,043
Butane	225,000	-	67,500	+ 6,626	=	$164,126
Pentane	120,000	-	42,000	+ 3,168	=	$ 81,168
TOTAL						**$578,212**

*For example, processing allowance for Gas and Propane would be determined as follows:

Gas
1,750 10^3m^3 x 25% x $10/$10^3$m^3 x 1.00 = $4,375 (operating)
1,750 10^3m^3 x 1.0 x $10/$10^3$m^3 x 20% = 3,500 (capital)
$7,875 (Processing Allowance)

Propane
4,000 m^3 x 30% x $10/$10^3$m^3 x 0.65554 $10^3m^3/m^3$ = $7,867 (operating)
4,000 m^3 x .27201 $10^3m^3/m^3$ x $10/$10^3$m^3 x 20% = 2,176 (capital)
$10,043 (Processing Allowance)

(b) **Purchased Valuation**

Purchased Cost = Purchased Quantity x Price

Product	Purchased Value
Gas	$60,000
Propane	75,000
Butane	45,000
Pentane	0
TOTAL	**$180,000**

(c) **Total Value of Hydrocarbons Injected:**

$578,212 + $180,000 = $758,212
(Proprietary) + (Purchased)

ii) **Breakthrough Valuation**

(a) **Average Heating Value of Injectants**

Product	Proprietary Volume (m^3)	Purchased Volume (m^3)	Gas Equivalent Volume Factor ($10^3m^3/m^3$)	Proprietary Volume (10^3m^3)	Purchased Volume (10^3m^3)	Total Volume (10^3m^3)	Heating Value Factor $GJ/10^3m^3$	Heating Value GJ
Gas	–	–	N/A	1,750.0	750.0	2,500	–	100,000
Ethane	0.0	0.0	0.28132	0.0	0.0	0.0	66.0	0
Propane	4,000	1,000	0.27201	1,088.0	272.0	1,360.0	94.0	127,840
Butane	2,500	500	0.23331	583.3	116.7	700.0	121.7	85,190
Pentane	1,000	0.0	0.20570	205.7	0.0	205.7	149.4	30,732
TOTAL				3,627.0	1,138.7	4,765.7		343,762

Average Heating Value of Injectants ($GJ/10^3m^3$) = $\frac{343,762.00}{4,765.70}$

= **72.13**

The gas equivalent factors and heating value factors are consistent with those used by the Gas Royalty Branch.

(b) **Breakthrough Price Per GJ**

	Total Net Gas Value $	Total Heating Value GJ	Gas Price ($/GJ)	Injectant Volume (%)	Breakthrough Price ($/GJ)
Proprietary Gas Component	112,875	70,000	1.61	76.11	1.23
Purchased Gas Component	60,000	30,000	2.00	23.89	0.48
TOTAL		100,000		100.00	**1.71**

(c) **Breakthrough Value**

Net Breakthrough Gas Participant Share (10^3m^3)	Net Breakthrough Gas Participant Share (GJ)	Breakthrough Price ($/GJ)	Breakthrough Value ($)
2,000	144,260 (2,000 x 72.13)	1.71	**246,685** (144,260 x 1.71)

iii) **Other Costs and Allowances**

(a) **Breakthrough Processing Allowance**

Net Breakthrough Volume 2,000 10^3m^3
multiplied by
Processing Allowance $20/$10^3m^3$ (Unit Operating Cost Rate + Capital Cost Rate)
Breakthrough Processing Allowance **$40,000**

(b) **Consumed Energy**

Fuel Gas Consumed:

125 10^3m^3 (5,000 GJs)

Weighted average value of gas (proprietary gas plus purchased gas):

$$\frac{\$112,875 + \$60,000}{70,000\ GJ + 30,000\ GJ} = \$1.73/GJ$$

Value of Fuel Gas = 5,000 GJs x $1.73/GJ
= **$8,650**

(c) **Transportation**

Gross Volume of Gas Injected: 2,500 10^3m^3
Gross Volume of NGLs Injected: 9,000 m^3

Gas Transportation Cost = 2,500 10^3m^3 x $7.50/$10^3m^3$ = $18,750
NGL Transportation Cost = 9,000 m^3 x $5.00/$m^3$ = $45,000
Total Transportation Cost = **$63,750**

iv) **Royalty Relief Calculation**

	Value of Hydrocarbons Injected	758,212
Less:	Breakthrough Value	246,685
	Subtotal	511,527
Less:	Present Worth @ 10%	51,153
	SUBTOTAL	460,374
Plus:	Nonhydrocarbon Fluids Injected	0
Plus:	Consumed Energy	8,650
Plus:	Transportation	63,750
Plus:	Breakthrough Processing Allowance	40,000
Plus:	Capital Amortization	375,000
	SUBTOTAL	947,774
Plus:	Overhead Allowance	142,166
Equals:	Total Costs Before Crown Interest	1,089,940
Times:	Crown Interest	100%
	SUBTOTAL	1,089,940
Plus:	Carry-Forward Costs	0
Equals:	Total Allowed Costs	$1,089,940

Royalty relief equals the lesser of:

Total Allowed Costs x Oil Royalty Rate = $272,485

($1,089,940) (25%)

OR

Participant's Working Interest Ownership x Tertiary Royalty = $900,000

(100%) (40,000 m^3 x $120/$m^3$ x .75 x 25%)

Royalty Relief = **$272,485**

8.0 APPENDIX

8.1 Blank Schedules

The following are schedules required for each reporting year (see Subsection 1.3).

Alberta
ENERGY

EOR - ESTIMATED COSTS SUMMARY

SCHEDULE 1

SCHEME	SCHEME ID #	FOR THE YEAR ENDING DECEMBER 31, ____
OPERATOR	OPERATOR ID	

COST CATEGORY	$
Unamortized Capital, January 1	
Capital Additions	
Hydrocarbons Injected	
Breakthrough Value	
Nonhydrocarbons Injected	
Consumed Energy	
Transportation Costs	
Annual Processing Allowance	
Carry-Forward Costs	

CONTACT PERSON	DATE PREPARED	TELEPHONE

Alberta

ENERGY

EOR - CAPITAL EXPENDITURE SUMMARY

SCHEDULE 2

SCHEME	SCHEME ID #	FOR THE YEAR ENDING DECEMBER 31, ____
OPERATOR	OPERATOR ID	

CAPITAL EXPENDITURE CATEGORY CODE	WELL/FACILITY NAME & LEGAL LOCATION	DESCRIPTION AND DETAILS OF CAPITAL EXPENDITURE	AUTHORITY FOR EXPENDITURE (IDENTIFIER)	AMOUNT $

TOTAL AMOUNT $	LESS GRANTS $	TOTAL NET CAPITAL ADDITIONS $

DATE PREPARED:	PAGE ___ OF ___

Alberta

ENERGY

EOR - NONHYDROCARBON FLUIDS INJECTED

SCHEDULE 5

SCHEME	SCHEME ID #	FOR THE YEAR ENDING DECEMBER 31, ____
PARTICIPANT	PARTICIPANT ID	

MATERIAL (CHECK ONE) CO_2 _____ N_2 _____ OTHER _____

	VOLUME * 10^3 m^3	COST $
JANUARY		
FEBRUARY		
MARCH		
APRIL		
MAY		
JUNE		
JULY		
AUGUST		
SEPTEMBER		
OCTOBER		
NOVEMBER		
DECEMBER		
TOTAL		

** MEASURED AT STANDARD SURFACE CONDITIONS*

DATE PREPARED

Alberta
ENERGY

EOR - CONSUMED ENERGY SUMMARY

SCHEDULE 6

SCHEME	SCHEME ID #	FOR THE YEAR ENDING DECEMBER 31, ____
OPERATOR	OPERATOR ID	

	FUEL GAS VOLUME 10^3 m^3	FUEL GAS GJ	ELECTRICITY COST $
JANUARY			
FEBRUARY			
MARCH			
APRIL			
MAY			
JUNE			
JULY			
AUGUST			
SEPTEMBER			
OCTOBER			
NOVEMBER			
DECEMBER			
TOTAL			

DATE PREPARED

Alberta
ENERGY

EOR - ESTIMATED OIL PRODUCTION

SCHEDULE 11

SCHEME	SCHEME ID #	FOR THE YEAR ENDING DECEMBER 31, ____
OPERATOR	OPERATOR ID	

MONTH	TOTAL OIL PRODUCTION (m^3)
JANUARY	
FEBRUARY	
MARCH	
APRIL	
MAY	
JUNE	
JULY	
AUGUST	
SEPTEMBER	
OCTOBER	
NOVEMBER	
DECEMBER	
TOTAL	

DATE PREPARED

Alberta

ENERGY

EOR - BREAKTHROUGH FUEL AND FLARE VOLUME

SCHEDULE 13

SCHEME	SCHEME ID #	FOR THE YEAR ENDING DECEMBER 31, ____
OPERATOR	OPERATOR ID	SCHEME GOR

	BREAKTHROUGH FUEL & FLARE 10^3 m^3
JANUARY	
FEBRUARY	
MARCH	
APRIL	
MAY	
JUNE	
JULY	
AUGUST	
SEPTEMBER	
OCTOBER	
NOVEMBER	
DECEMBER	
TOTAL	

DATE PREPARED